A Staff Report On:

LIKELY IMPACT OF RESTRUCTURING ON SYSTEM RELIABILITY

Testimony

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Table of Contents

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LIKELY IMPACT OF RESTRUCTURING ON SYSTEM RELIABILITY

Introduction

The 1996 Electricity Report Committee has asked parties to address the concern, "What are the likely changes in system reliability, both during the transition period and in the long term, resulting from the CPUC proposal?"

Restructuring and the emergence of competitive electricity markets could impact system reliability in a number of ways. This testimony focuses on three such areas: 1) potential effects on system operating reliability; 2) potential effects on transmission system expansions and upgrades; and 3) potential effects on the reliability of individual generating facilities. This testimony describes how reliability is maintained in the existing system, explains how restructuring could affect the system, identifies steps being taken to assure reliability, and discusses the implications for system reliability.

Defining System Reliability

Because restructuring efforts in California directly affect the operation and planning of the interconnected bulk power system,[1] we will examine the effects of restructuring on the ability of the bulk power system to avoid outages and continue to supply electricity with the appropriate frequency and voltages.

System reliability is a measure of the ongoing ability of the bulk power system to supply electricity with the appropriate frequency and voltage. Generally, the ability to serve customers must be maintained when outages of some generation and/or transmission facilities occur. The North American Electric Reliability Council (NERC), the Western Systems Coordinating Council (WSCC), and individual utility reliability criteria set the physical standards that determine the level of reliability. This requires control system operators to keep the system within voltage and frequency limits.

Service reliability, which is a measure of the ability of the distribution system to deliver power from the generation and transmission portions of the system to the end user, is not addressed in this discussion. Although impending restructuring has already been credited with an apparent

1 The bulk power system delivers power, in the quantities needed and of the quality required, to the distribution systems for distribution to the end users.

reduction in distribution reliability in the PG&E system, further study is needed before this question can be adequately addressed.[2]

RESTRUCTURING IMPACT ON SYSTEM OPERATING RELIABILITY

CPUC Approach to Ensuring Operating Reliability

Restructuring changes the traditional functions and relationships used to maintain operating reliability. The California Public Utilities Commission (CPUC) restructuring decision (the Decision) directs jurisdictional utilities to create an independent system operator (ISO) to perform the basic functions of traditional electric utility control area operators. The ISO is a new and distinct legal entity, responsible for the physical integrity of the power system. Its major objectives will be to assure system operating reliability and to operate the integrated system on a least-cost basis.[3]

To perform these functions under the CPUC proposal, the ISO will serve as a control area operator for the State's three major Investor Owned Utilities (IOUs) and any other utilities who choose to replace their existing control operators. The ISO will be responsible for operating the network in accordance with NERC and WSCC operating criteria for voltage, frequency and other standards. It will coordinate scheduled generation resources on a day-ahead and hour-ahead basis to ensure a reliable and least cost dispatch of power. It will acquire and control ancillary services to maintain voltage support, provide emergency reserves and maintain system stability. It will also balance load in real time, maintaining adequate generation capacity in reserve. The CPUC Decision indicates that the ISO should have "physical control of the operation of some generation facilities in order to balance the system and respond to unforeseen difficulties." Finally, the CPUC Decision prohibits the ISO from owning any generation resources. Resources used both for commercial purposes and to maintain system operating reliability will be acquired through competitive markets.

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2 Petersen, Melody, "Why PG&E has let the lights go out in the state" and "PG&E bills us for work it doesn't do," and Rebecca Smith, "Watchdogs look the other way," *The Sacramento Bee*, May 26, 1996.

3 CPUC Decision 95-12-063 (December 20, 1995), as modified by D. 96-01-009 (January 10, 1996), hereafter referred to as "the Decision." "The ISO will have primary responsibility for determination of the final operation and dispatch of the system to preserve reliability and achieve the lowest total cost for all uses of the transmission system." (p. 32) "The ISO will coordinate the scheduled nominations from the Power Exchange and the bilateral transactions to determine any redispatch that would be necessary to meet the twin objectives of assuring operational reliability and achieving least cost use of the system." (p. 35)

WEPEX Approach to Ensuring Operating Reliability

Under the current plan, the Western Power Exchange (WEPEX)[4] group will design and implement the ISO. WEPEX addresses at least three important challenges in this regard. First is the proper design and structure of the ISO so that it maintains its independence and long term organizational integrity and continuity. Independence is necessary so it will operate in an impartial manner, and organizational integrity is imperative to help assure that it operates reliably over time. Second is the complex new computer control, monitoring and communications capabilities — data base and control mechanisms — the ISO must have in place to control generation and operate the transmission system to assure reliability and least cost goals. To meet the CPUC's goal, this system must be in place and operating by January 1, 1998. Third, WEPEX must define and put in place the mechanisms to carry out those complex grid management responsibilities and authorities assigned to it by the CPUC.

These three challenges — organizational structure, computer technology capabilities, and defining and instituting management responsibilities and authorities — are highly interrelated. The way in which these challenges are met will have important implications for system operating reliability.

How the ISO is designed and structured will determine the stability of the organization over time. Lack of organizational stability could affect reliability through high turnover rates and loss of experienced staff and management, frequent organizational restructuring and other changes. Organizational structure will also affect the independence of the ISO, its decision making processes, and how it performs its functions. As proposed by WEPEX, the governing board of the ISO is composed primarily of market participants with commercial interests in the outcomes of the board's decisions. Of the 15 directors proposed by WEPEX, only four represent end users and only two are public participants who do not represent commercial interests.[5]

Selecting and installing a major new computerized operating system represents a significant technical challenge. Because of the relatively short time frame for implementing ISO control, existing computer and software technologies will likely have to be adapted for the ISO's use. But existing computer technologies may be limited in their capabilities to respond to both the increasing transaction volume resulting from competitive markets, and the ever shorter response times required by the new market structure.

Assuring that the ISO can perform its grid management responsibilities is yet another challenge for WEPEX. As noted above, the CPUC requires that the ISO perform all of the grid management functions of traditional utilities, but it is prevented from owning the generation resources — the

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4 WEPEX is the group of three Investor Owned Utility companies jointly responding to the CPUC Decision.

5 *Joint Application of PG&E, SDG&E and SCE for Authorization to Convey Operational Control of Designated Jurisdictional Facilities to an Independent System Operator. Before the Federal Energy Commission*. April 29, 1996, p. 22.

ancillary resources — needed to maintain reliability and balance the grid.[6] This raises important questions concerning the relationship between the ISO grid management responsibilities and its capabilities to fulfill those responsibilities. Two important questions here are 1) how the ISO will acquire adequate amounts of generation resources to maintain the grid, and 2) what responsibilities and capabilities it will have to manage the grid in order to maintain reliability.

Among other things, the ISO is responsible for coordinating two commercial markets (day-ahead and hour-ahead) and one real-time market from which it will obtain generation for both power and reliability. One commercial market, the Power Exchange (PX), is essentially a pool based spot market, based on supply and demand bids. The non-PX market is based on bilateral contracts. These day-ahead and real time markets provide the generation resources necessary for maintaining short term operating reliability. As part of its operating procedures, the ISO must determine the amount of generation it will require to meet its reliability related responsibilities. Included here will be voltage support, operating reserves, frequency control, load following, etc. It will then obtain and schedule these resources through a day-ahead competitive auction. When real time generation-load imbalances occur, the ISO will rebalance the system with reserves obtained through its auction.

Under the WEPEX proposal, the ISO is responsible for second-to-second balancing of generation resources and loads while ensuring the safe and reliable operation of the transmission system. This involves four areas of responsibility: grid management under normal conditions, management of system emergencies, acquisition of various ancillary services necessary to maintain operating reliability, and administration of overgeneration protocols. The ISO has a broad range of authority and control over technologies and resource operators connected to the system to assure operating reliability. For example, "The ISO will have exclusive authority to direct the operation of all facilities that affect the reliability of the transmission grid under its control."[7] Moreover, transmission owners and power sellers and buyers are required to carry out the ISO's equipment operating orders necessary for maintaining system reliability. The ISO can exercise direct control over a number of facilities, including opening and closing transmission line circuit breakers or switches, and controlling substation equipment such as voltage control equipment, breakers, and the like. It also controls remedial action schemes (RAS) computers and other equipment for monitoring and managing the grid.

Issues and Assessment

WEPEX has devoted considerable attention to the task of designing the ISO with an organizational structure, and with the authority and capabilities, to maintain operating reliability under a variety of conditions. WEPEX has considered and designated: the structure and organization of the ISO; its mandate, authority and capabilities to manage the system and control the various technologies and actions that contribute to reliable system operation; and its acquisition and scheduling of ancillary services through competitive auction.

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6 It should be noted that WEPEX also assigns to the ISO reliability and grid management responsibilities. However, WEPEX tries to remove the ISO from a direct role in setting spot electricity prices by including PX and non-PX parties in an iterative process that produces hourly dispatch schedules and prices.

7 WEPEX Application, p. 45.

During the transition period, we anticipate start-up problems typically associated with the implementation of new, complex, highly technical systems. These include complications associated with the installation of a complex system designed to control operations on a heretofore untried scale. This will involve integrating existing monitoring and control equipment into a new system, and transferring data from existing utility systems to new systems. These potential problems should be monitored during the startup period to ensure their resolution.

The structure of the ISO's board of directors may also be a concern. As noted above, the ISO's governing board is heavily biased toward commercial interests, with only limited representation by public entities. The California Energy Commission has expressed concern with this representation formula because of the potential to bias governing decisions to benefit those interests at the expense of some end users and the public.[8]

The ISO will have to adjust to accommodating a significant increase in transaction volume compared to the experience of traditional systems. It will also have to adjust to a dynamic process that can change unit commitments and schedules up until the hour before generation is dispatched. Currently, the transaction scheduling for a single IOU (PG&E) amounts to 175 day-ahead transactions stored in nine computer system pages. During the following operating day, intra-day and hour-ahead changes require an additional 15 system pages. Combining the several utilities in the State multiplies this volume. The addition of the Power Exchange and direct access scheduling is expected to increase this scheduling volume by two to three orders of magnitude.

The ISO will have to put in place sufficient capabilities and authority to maintain reliable operating conditions under a range of system conditions varying from normal operation to emergency situations. Also, as a means of reducing the ISO's total scheduling volume, the designation of scheduling coordinators (SCs) is under consideration. Like the PX, the SC would act as a consolidator, bridging the market activity of the PX and Direct Access contracts with the system reliability requirements of the ISO. The SC would be essentially a mini-pool administrator who must cooperate with other SC entities, PX and Direct Access parties and the ISO.
The acquisition and scheduling of ancillary services will be subject to many of the same concerns as for bulk power transactions. Parties to PX and Direct Access transactions will be able to "self-provide" and "self-source" ancillary services as they see fit. The ISO, however, is ultimately responsible for procuring sufficient levels of ancillary services to meet all system reliability requirements, under both normal and emergency conditions.

Summary

Restructuring will create problems related to simultaneously integrating the existing multiple control centers into one ISO, accommodating the greatly increased data processing load of operating an hour-ahead market, integrating the PX with Direct Access schedules, and acquiring and scheduling unbundled ancillary services. The tight time schedule, which calls for commencement of this operation on January 1, 1998, presents a difficult challenge. While WEPEX appears to be working out solutions to all these problems, there remains much uncertainty and the opportunity to overlook something.

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8 John D. Chandley, *California Energy Commission's Comments on the WEPEX Applications*, May 28, 1996, pp. 38-41.

RESTRUCTURING IMPACT ON TRANSMISSION EXPANSION

Introduction

An important part of assuring long term system reliability is the capability to maintain, upgrade and expand the bulk power system as necessary. Many consider this one of the most difficult challenges in restructuring the traditional utility system along more competitive lines.

Utility companies have traditionally pursued transmission upgrades and expansions in order to maintain reliability requirements, meet load growth, and access low cost power supplies. Under this model, utilities, operating independently or in coordination with other utilities and the WSCC, were responsible for all activities required to expand the transmission system — determining need, planning, providing security, financing and other network expansion tasks — as part of their overall resource planning function. In the case of the IOUs, the transmission investment would be rate based and the Transmission Owning Utility (TOU) would earn a return on its investment.

This integrated approach to transmission expansion is drastically altered in a deregulated regime in which generation, transmission, and distribution functions are "unbundled" and owned or controlled by different entities. The CPUC's December 20, 1995, Decision requires a functional unbundling of the IOUs. As discussed above, the Decision calls for the creation of an independent system operator to manage the transmission system for both reliability and least cost purposes. The Decision also creates a Power Exchange which buys power from utilities and independent producers, based on competitive supply bids, and sells it, based on competitive demand bids, to utility distribution companies, aggregators or other middle men for distribution to end users. The Decision also requires IOUs under its regulation to sell power only into the PX during a five-year transitional period. During this period, IOUs may not sell power in bilateral markets. In addition, the Decision encourages regulated utilities to divest themselves of fifty percent of their fossil-fired generation assets (15% of their total generation) during the transition period. Finally, the Decision requires the State's IOUs to form utility distribution companies (UDCs) which are responsible for the distribution of power and the upkeep and maintenance of their retail distribution systems. UDCs remain under CPUC regulation.

What implications do these restructuring requirements have for the transmission upgrades and additions required for long term system reliability? First, unbundling transmission from generation and distribution and creating an ISO could reduce many of the direct economic incentives TOUs formerly had to upgrade or expand transmission facilities. In a market based regime, economic incentives for transmission expansions will be diffused among a number of parties that could benefit from such additions rather than concentrated among existing owners. Industry restructuring could also alter the way transmission capital additions are financed. For example, those who benefit the most from network expansion will pay its full costs. FERC has already moved in this direction in its marginal cost transmission pricing policies.

Second, from a planning and development perspective, decentralizing the generation, transmission and distribution functions could mean that no single entity is responsible for all or even most of the traditional activities of determining need, planning, financing, licensing and building transmission capacity additions. Under this unbundled industry model, transmission expansions could be identified and proposed by those who benefit directly from the expansion, and engineered and constructed by a completely different set of interests, e.g., IOUs, power marketers, municipal utilities, independent generators, and utility distribution companies.

In short, the unbundling of the generation, transmission and distribution functions may require new incentives for transmission expansion, new planning methods, and new approaches for integrating the needs of various parties, while providing acceptable system reliability.

The CPUC Approach To Transmission Expansion

The CPUC's December 20, 1995, Decision addresses both of these fundamental issues - how to encourage investment in transmission expansions, and how to conduct transmission planning, analyses and expansions.

Investment Incentives

The CPUC believes that transmission system upgrades — presumably for both reliability and commercial purposes — should be market driven.[9] This means that investments in the transmission system should be motivated by a calculation of potential costs and benefits. The CPUC's vision of a locational spot market is one approach for encouraging transmission upgrades.[10] According to this view, spot price differences between locations on the grid — or transmission congestion costs — should provide the incentive for investments in transmission system upgrades. Parties wishing to reduce their transmission congestion costs could invest in transmission upgrades in order to reduce their transmission costs if the costs of network expansion are less than the costs of congestion. Power producers wishing to expand commercial power sales into new markets could also invest in transmission expansions.

The Decision also calls for the creation of transmission congestion contracts (TCCs) that would be administered by the ISO. These contracts could provide compensation to parties for upgrading the grid. As a hedge against future transmission price increases, parties investing in transmission capacity would receive TCCs that would entitle them to collect congestion rents as the system once again becomes congested.[11]

In cases where market incentives are insufficient to encourage needed transmission expansion, the CPUC proposes a "regulatory backstop" to assure that needed transmission facilities are planned

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9 CPUC Decision, p.41. "(T)he principal impetus for transmission investments should come from market forces manifest in the requests from customers who are willing to pay for the upgrades in exchange for incremental transmission congestion contracts and protection from future transmission congestion costs."

10 Ibid., pp.28-29.

11 Ibid., p. 39.

and constructed and that the costs of such facilities are allocated among parties that benefit from the facilities.[12]

Transmission Planning

The Decision is not specific about which entities should be responsible for transmission planning and construction. The Decision indicates that the "ISO should evaluate the physical conditions of the transmission grid and report on the ability to continue existing transmission congestion contracts or the opportunities for upgrades needed to maintain reliability or to increase efficiency."[13] But, as noted above, the CPUC also believes that the principal impetus for transmission investments should come from market forces.

The Decision does not indicate what parties should be responsible for undertaking capacity additions, or what roles parties would play. The Decision does, however, indicate that recommendations for upgrades should be made to the Western Regional Transmission Association (WRTA), FERC, and the CPUC and that a joint siting body consisting of these parties may be able to facilitate siting decisions for transmission projects.

The WEPEX Approach to Transmission Expansion

WEPEX outlined an approach to transmission expansion in their April 29, 1996, filing with the FERC. WEPEX treats the need for encouraging and planning new transmission facilities in a competitive system as follows:

Incentives

As noted above, the CPUC expresses a preference for market driven transmission expansions, while providing a backstop approach in cases where market incentives fail to encourage adequate investments. WEPEX follows the CPUC Decision and proposes two potential approaches to transmission expansion — a market driven approach and a backstop approach. The market approach allows any party or combination of parties, except for the ISO, to propose transmission expansions or upgrades. The project proposers (sponsors) can then commit to pay the full costs of expansion as the presumed beneficiaries of the expansion. Alternatively, in cases where a project proposer believes there is a need for a transmission upgrade or expansion but is unwilling to bear

[12] Ibid., p. 41. "In the absence of willing customer requests, investments in the transmission grid should be made only in the case of a showing to the regulators that there has been a market failure leaving important modification undone because of an inability of market participants to agree on a sharing of the costs and benefits. In the context of cooperative federalism, the regulators and appropriate authorities should maintain the prerogative to authorize the permitting and assign the costs of the investment and the benefits of incremental transmission congestion contracts among the various users of the system."

[13] Ibid., pp. 40, 41.

the entire project costs because others may also benefit from the project, the proposer can present its case to an impartial decision body, which would determine the need for the project and what parties should pay for the expansion, based on benefits from the project. This is one way of addressing both the need for transmission expansions and a way of addressing the "free rider" problem.

While this is the same general approach advocated by the CPUC — providing for both market-based and backstop approaches — there are three important differences in the way WEPEX treats the market incentives relied on by the CPUC to encourage expansion. First, the WEPEX proposal does not rely on TCCs as partial incentives for market based transmission expansions, as does the CPUC December 20, 1995, Decision.

Second, the WEPEX approach to locational spot pricing proposed to the FERC seems to be substantially different from the locational pricing scheme envisioned by the CPUC. The WEPEX proposal divides all of California into four separate pricing zones based on historical system data; PG&E is divided into three pricing zones and SCE and SDG&E become a single zone with one spot price for both service areas. The aggregation averages locational price differences within each zone and masks any significant pricing differences that may encourage transmission additions or low cost generation additions.

Third, WEPEX distinguishes between transmission projects required for commercial and for reliability purposes. While additions for commercial purposes should be market driven, WEPEX assigns transmission owners the responsibility of determining when reliability related transmission expansions are needed, and requires them to design and plan the project and to include the capital costs of the facilities in their revenue requirements. The revenue requirements are then part of the embedded costs paid by transmission users through transmission access fees.

Transmission Planning and Development

As noted above, under the WEPEX proposal, responsibility for determining the need for reliability related transmission upgrades falls to the transmission owners whose systems will be affected. Transmission owners also have the responsibility to determine what facilities should be constructed. Once this is determined there are several layers of review and oversight by different parties. The ISO will perform an operational review of the proposed project to ensure that the proposed facilities supply the proper operating flexibility and integrate with the existing grid. The transmission-owning IOUs proposing the projects will also be responsible for guiding the proposed project through the State regulatory process. In addition, projects must be coordinated and reviewed through WRTA.

Issues and Assessment

The central question here is, how will restructuring directions provided by the CPUC and implemented by WEPEX affect incentives for transmission expansion and transmission planning?

The CPUC Decision provides both market and backstop approaches to transmission expansion, although it clearly favors a market based approach. We would be concerned if the CPUC relied on a market based approach for transmission expansions <u>for reliability purposes</u> because of the current status of market incentives. Neither locational pricing nor TCCs are sufficiently well developed by WEPEX at this time to be relied on for that purpose.[14]

Fortunately, both the CPUC and WEPEX recognize a need for "backstop" approaches for adding transmission capacity in cases where upgrades or transmission additions are needed but market forces fail to stimulate interest or investments to meet that need. WEPEX goes a step beyond this backstop approach by assigning transmission owners the responsibility of identifying reliability problems and a method for planning and financing projects considered needed by the TOU and its regulators. These backstop methods increase confidence that transmission projects needed to rectify reliability problems will be planned and constructed.

Although WEPEX has not focused sufficient attention on locational pricing or TCCs to this point, those mechanisms do offer promising market methods of encouraging investments in transmission additions. Additional work in these areas is needed and should be encouraged.[15]

There are also uncertainties about the roles of other parties in the transmission planning and review process that should be clarified in the immediate future. Parties, including utilities and involved state regulators, need to clarify what specific role WRTA or an RTG-like organization will play in planning and assessing new projects, and the impacts of those projects on the reliability of California's system and relevant parts of the WSCC. While WRTA has already been constituted, its role in the transmission planning process is not yet clearly defined. In addition, it should be noted that while the CPUC assigns a role for the ISO in transmission planning — identifying opportunities for grid expansions to enhance reliability and economic efficiency — WEPEX specifically excludes the ISO from such a role.

In sum:

1. The restructured system will not have to rely on market incentives to encourage transmission additions for reliability purposes; backstop approaches proposed by both the CPUC and WEPEX can be implemented to ensure reliability related projects are built.
2. Greater effort should be devoted to implementing systems of locational pricing and TCCs in the near term to ensure market incentives for reliability related projects are effective in the long term.
3. Uncertainties concerning the role of parties in the transmission planning process, especially the ISO and WRTA, should be addressed and resolved as early as possible.

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14 Staff comments reflecting a more detailed critique of both the CPUC's and WEPEX's views on locational pricing and TCCs are provided by Susan Bakker in a coordinated filing in these proceedings.

15 See, for example, James Bushnell and Steven Stoft, "Electric Grid Investment Under a Contract Network Regime," *Power* document PWP-034, September 1995. Bushnell and Stoft's work attempts to design a market-based approach to TCCs that would provide incentives to encourage beneficial transmission expansions and discourage expansions that would increase total system costs or reduce reliability.

RESTRUCTURING IMPACT ON GENERATING FACILITY RELIABILITY

Introduction

Facility reliability is a measure of the likelihood that a generating facility, or unit, will deliver the desired power output when required.

The Traditional Approach

Under the utility monopoly regime of the past, the utility companies determined the level of reliability required of individual facilities, and the CPUC was asked to approve the cost of providing it. The utilities typically designed, procured and installed rugged power plant equipment under rigorous quality control programs, incorporated redundant critical systems and components, designed the plant for easy maintainability, and implemented a thorough maintenance program.

Under PURPA, the majority of privately owned power plants were, in fact, built to reliability standards equal, or nearly equal, to those of utility plants. The inherent profitability of power plants operated under Standard Offer contracts made it easy to justify paying for this accustomed level of reliability. At the same time, penalties for poor reliability were somewhat muted. If a plant failed to meet the level of reliability required by the power purchase contract, capacity-based payments could be reduced, but in subsequent years.[16]

The Transition Period

When Standard Offer power purchase contracts were no longer available, the electric power industry began its move toward a competitive market. There is now an incentive for owners of privately owned power plants to build their facilities with less inherent reliability, at substantial capital cost savings. They may install cheaper, less reliable equipment, and forego installing redundant equipment. There is likewise an incentive for these owners to save on operating expenses by reducing maintenance expenditures, stretching maintenance intervals and minimizing the stock of spare parts. A portion of these savings is justified, as some operators have turned to Reliability Centered Maintenance, which attempts to spend maintenance dollars as actually needed, rather than following arbitrary, and generally conservative, recommendations from equipment manufacturers.

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16 Historic comparisons of utility plant versus privately owned plant reliability generally show the private plants to be *more reliable*. This is not a valid comparison, however, for two reasons. First, these PURPA-era private facilities were built largely to utility reliability standards, but with more modern (and thus more reliable) technology and equipment. Second, these private plants are all much newer than the 20- to 40-year-old utility power plants to which they are compared, and will tend to be more reliable for this reason.

Some privately owned facilities have been built and maintained so cheaply, however, that their reliability suffers to the point of endangering their financial survival. Power plants have been constructed which lack any of the typical component redundancy. Failure of a single pump, for example, can disable the entire plant for hours or days. Plant owners have extended intervals between maintenance overhauls, or entirely foregone the overhauls. Still other owners have failed to build the financial reserves needed for eventual replacement of consumable components, such as gas turbine blades.[17]

In addition, with the demise of Standard Offer 4 contracts, which required the utility to accept power whenever the owner generated it, these privately owned facilities are now subject to dispatch by the utility. They now find themselves providing power not as baseload, but as load followers or as peakers. The high loads, frequent dispatch cycles and high ramp rates demanded of these facilities take a heavy toll in wear and tear on equipment, increasing maintenance needs and making it more likely that an inadequately maintained facility will fail to operate reliably.

The Long Term

Under a competitive electricity market, there may or may not be a need to specify and demand any certain level of reliability from individual generating units; the future is uncertain. In the past, the vast majority of power outages were not the result of power system failures, but of distribution network failures. To date, power outages caused by generating facility failures are practically unheard of in the western United States. Large generating reserve margins maintained on the system, combined with redundant transmission paths, have served to ensure system reliability regardless of individual generating facility reliability levels. In the future, the competitive market may be expected to deal quickly and harshly with facilities which are insufficiently reliable. Strong economic pressures remain for power plant owners to minimize both capital and operating expenditures, but it will be the plant owner's responsibility to balance cost minimization with adequate reliability.[18] If the unit cannot provide the required output when dispatched, its owner must pay for replacement power. It is uncertain at this time how generating facility owners and operators will respond to these pressures.

A related question develops regarding generating facility reliability under a competitive market. Whenever a unit is constructed, environmental impacts are generated. If, under a competitive regime, significant numbers of generating units are built that prove unreliable, which then fail and are shut down, this could create significant environmental impacts. While it is often acceptable, in spite of environmental impacts, to allow the siting of a facility that will benefit society, i.e., provide electric energy, it is difficult to justify allowing the attendant impacts if no benefit will ensue due to project failure.

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17 Source: McGraw Hill, *Operational Experience in Competitive Electric Generation*, 1995, and Infocast, Inc., *Rescuing Troubled Projects in California*, February 24, 1995.

18 A recent power plant siting case before the CEC, the San Francisco Cogeneration Project, illustrated confusion on this point. The developer initially planned not to install any redundant equipment in the steam side of this combined cycle facility, then later decided to include the equipment when impacts on reliability were questioned.

However, a CEC staff study of failed power plants in California has shown that few failed power facilities may remain shut down. Typically, the project is rescued. It may be restructured financially by the original owner and operated under lesser constraints (reduced fuel prices, extended debt payments). Or a new owner may take over, totally restructuring project finances, making necessary physical modifications, and operating successfully where the original project could not. The number of truly failed projects which yield unacceptable environmental impacts may thus be negligible.

A further unknown is the extent to which other technologies may move to satisfy capacity requirements. Distributed generation, the placing of small-scale generators near the loads they serve, may see increasing popularity, particularly where transmission constraints pose significant problems, or distribution asset utilization can be improved. Environmentally acceptable technologies, including fuel cells and solar photovoltaics, may make distributed generation even more popular as technological advances drive prices down. We cannot predict at this time how such changes may affect system reliability in the long term. In the short term, California's overcapacity situation should discourage any significant construction of new facilities, and thus any changes they may cause.

Summary

It is impossible at this time to predict how restructuring will influence generating facility reliability, and what effect that will have on system reliability. In the short term, overall system reliability will see few, if any, significant changes. In the long term, the State should monitor generating facility reliability and the ISO/WEPEX responses to any problems, and prepare to respond to any ongoing problems. The Commission might effect necessary corrections to larger facilities through its energy facility siting process. Smaller facilities, those below the Commission's 50 MW siting threshold, should pose lesser problems due to their smaller capacity.

CONCLUSIONS AND RECOMMENDATIONS

Operating Reliability

While WEPEX has devoted considerable attention to the task of designing an organizational structure with the authority and capabilities to maintain operating reliability under a variety of conditions, in the short term we anticipate the possibility of start up problems typically associated with the implementation of new, complex, highly technical, and untried systems. These include complications associated with the installation of a complex system designed to control operations on a heretofore untried scale. It will involve integrating existing monitoring and control equipment into the new system, and transferring data from existing utility systems to new systems and other tasks.

The ISO will have to accommodate a significant increase in transaction volume compared to that currently handled by the IOUs. It will also have to employ a dynamic process that can change generating unit commitments and schedules up to the hour before generation is dispatched. The question is, will the ISO have sufficient capabilities and authority to maintain reliable operating conditions?

Fundamentally, there is uncertainty as to whether the ISO has both the means and incentives to maintain system reliability. Our review suggests that while WEPEX has considered and proposed means for the ISO to assure operating reliability, uncertainty as to the effectiveness of the ISO remains, and the State should continue to monitor the creation of the ISO and be prepared to respond to issues of maintaining system reliability.

Transmission Expansion

Our review raises several issues concerning how transmission additions needed for reliability can be implemented in a competitive, decentralized system.

The CPUC's competitive market approach for encouraging transmission expansions relies primarily on new and untested market incentives to encourage investments in transmission upgrades and expansions. While we believe this approach is promising, we have concerns with how WEPEX has chosen to implement both locational pricing and TCCs. Considerably more work on both of these concepts is needed.

Both the CPUC and WEPEX recognize a need for "backstop" approaches for adding transmission capacity in cases where upgrades or transmission additions are needed, but market forces fail to stimulate investment to meet that need. WEPEX goes beyond the backstop approach envisioned by the CPUC by assigning transmission owners the responsibility of determining reliability based need and adding new transmission facilities to meet reliability problems. These backstop methods increase confidence that those transmission projects needed to correct reliability problems stand a chance of being developed, over the long term or until market incentives for this purpose are well understood and implemented.

Uncertainties about the roles of parties such as RTGs, and perhaps even the ISO, in the transmission planning and review process should be clarified in the near term. Parties, including utilities and involved State regulators, need to clarify what specific role RTGs such as WRTA will play in planning and assessing new projects, and the impacts of those projects on the reliability of California's system and relevant parts of the WSCC. In addition, the CPUC Decision indicates that the ISO should have a role in transmission planning by identifying opportunities for additions to promote reliability and economic efficiency, while WEPEX specifically excludes the ISO from a role in the planning process.

In conclusion, during the transition period and possibly over the long term, backstop approaches may have to be exercised to provide adequate means for planning and financing transmission expansions for maintaining system reliability. Market based incentives such as locational pricing and TCCs are promising, but will require considerable work before they can be effectively implemented. In addition, while most parties appear to believe that WRTA will play a significant role in regional transmission planning, that role is uncertain at this point. WRTA's role in regional and subregional planning needs clarification.

Generating Facility Reliability

We believe that the impact of generating facility reliability on overall system reliability will not pose significant concerns in the short term under a restructured competitive market. Over the long term, however, we cannot predict with any certainty what effects may ensue. We believe the State should monitor developments in generating facility reliability and be prepared to respond should problems appear.

WITNESS QUALIFICATIONS
for
Steve Baker

Mr. Baker, a Senior Mechanical Engineer, has worked eight years in the Engineering Office of the Energy Commission's Energy Facilities Siting Division, supervising and performing power plant siting case analyses in the areas of Reliability, Efficiency, Noise and Mechanical Engineering.

Before coming to the Energy Commission, Mr. Baker worked for Bechtel Power Corporation in the mechanical design, quality assurance and startup of nuclear and coal-fired power plants. He also worked for Southern Pacific Land Company in the permitting of hydroelectric and wind power plants, and in managing company involvement in an operating geothermal power plant.

Mr. Baker holds a Bachelor of Science degree in Mechanical Engineering from Cal Poly, Pomona, and a Master of Business Administration degree from California State University, Long Beach, and is registered in California as a Professional Engineer.

WITNESS QUALIFICATIONS
for
Roger L. Johnson

Mr. Johnson is a Senior Mechanical Engineer in the Engineering Office of the Energy Commission's Energy Facilities Siting Division, having worked for the Commission for 15 years. He currently represents the Commission in several electric power industry restructuring forums, and was previously Technical Director of the Commission's *Electricity Report*.

Before coming to the Energy Commission, he served the U.S. Department of Energy in energy R&D and commercialization. More recently, he spent a year on loan to the International Energy Agency as head of the Technology and R&D Division.

Mr. Johnson holds a Bachelor of Science Degree in Mechanical Engineering from Clarkson University, NY, and both a Master of Science Degree in Industrial Engineering and an MBA from Stanford University. He has also completed further studies in advanced management at the Executive Program, University of California, Davis, and the Wharton Executive Education program, University of Pennsylvania.

WITNESS QUALIFICATIONS
for
James McCluskey, Ph.D.

Dr. McCluskey, a Transmission Program Specialist in the Engineering Office of the Energy Facilities Siting Division, has worked 18 years for the Energy Commission. He has been involved in many policy issues, including transmission access, pricing, reliability and planning. He has prepared testimony for the FERC and was a primary author of the Commission's 1991 Garamendi Report on transmission planning.

Dr. McCluskey holds a Bachelor of Arts degree from San Jose State University, and a Ph.D. in Political Science and Public Policy from the University of Washington.

WITNESS QUALIFICATIONS
for
Albert McCuen

Mr. McCuen is a Senior Transmission Planner in the Engineering Office of the Energy Facilities Siting Division. He has worked 20 years for the Energy Commission, directing and performing transmission analyses for various policy issues and for power plant siting cases .

Prior to joining the Energy Commission staff, Mr. McCuen worked seven years as an electrical engineer in private industry, engaged in the design and construction of power plants and transmission facilities. He holds a Bachelor of Science degree in Electrical Engineering.